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CAISO Standards for Transmission Economic Assessment Methodology (TEAM) Application

I. Introduction

This document provides a preliminary foundation to begin addressing the issues raised in Investigation (I.) 05-06-041, as clarified in the "Scoping Memo and Assigned Commission Ruling," dated August 26, 2005. The Scoping Memo described the issues as:

- What general principles or methodologies should be employed in assessing the economic benefits of transmission projects within the Commission's jurisdiction?
- Is the CAISO's TEAM approach a reasonable methodology for assessing the economic benefits of transmission projects?
- What validation is needed by the Commission in order to rely on a CAISO assessment of need in a Commission certification proceeding for a transmission project proposed for its economic benefits?
- If the Commission determines in a certification proceeding for a transmission project proposed for its economic benefits that a CAISO assessment of need has been adequately validated, are there additional requirements that must be met in the Commission's determination of economic benefits and need for the project?
- For those certification proceedings for transmission projects proposed for economic benefits where there is no validated CAISO assessment of need, what requirements should the Commission adopt for consideration of economic benefits and need?

In particular, the CAISO sets forth the basic principles or elements of the CAISO's Transmission Economic Assessment Methodology (TEAM) approach and places these elements on a continuum from mandatory to permissive. As noted during the recent prehearing conference in this proceeding, the CAISO endeavored to prescribe TEAM at its lowest level of detail. However, in developing this document, the CAISO determined that an overly prescriptive application of TEAM is unlikely to be beneficial or practical. TEAM represents the best synthesis of recent advances in applying dynamic bidding strategies in a network model and in developing a consistent benefits methodology. Nevertheless, the implementation and application of TEAM is not, and should not be, static. Rather, TEAM's implementation should reflect an evolutionary process that allows professional engineers and economists the flexibility to pursue creative refinements in various study areas. Accordingly, in order to avoid stifling the critical judgment of transmission planners, the CAISO has defined the fundamental TEAM elements as a reasonably broad set of core principles.

There are two consequences of defining TEAM as broad principles. First, this document does not attempt to repackage or distill TEAM from an explanatory standpoint. The CAISO has explained the application of TEAM in detail in its *Transmission Economic Assessment Methodology* Report submitted in June 2004 to the Commission in I.00-11-001 ("TEAM Report") and in its *Economic Evaluation of the Palo Verde-Devers Line No. 2* Report and accompanying technical appendices.[1] Attempting to condense these documents is likely to create significant confusion without enhancing participants' understanding of TEAM. These documents will continue to form the basis of the CAISO's workshop discussion, including a description of how the principles were applied to Palo Verde-Devers No. 2 ("PVD2"). However, the detailed descriptions and

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[1] The TEAM Report evaluated Path 26. (See CAISO website: http://www.caiso.com/docs/2003/03/18/2003031815303519270.html.) The TEAM PVD2 Report is also on the CAISO's website at http://www2.caiso.com/docs/2005/01/19/2005011914572217739.html.

justifications contained in those documents regarding the underlying theories and formulas utilized in TEAM will not be duplicated here.

Second, and directly related to the issues in this proceeding, a correlation exists between the level of prescription in defining the elements of TEAM and the nature and ability of the Commission to "validate" application of those elements in order to rely on an CAISO assessment of need. For example, if the Commission believes its authority or ability to defer to an CAISO's need assessment is somehow contingent on an ability to validate a recipe-like application of TEAM, the present approach would need to be modified to support this outcome. Whether or not such a limitation exists, the CAISO nevertheless believes that the present investigation and the CAISO's submission have value in facilitating the transmission siting process. As noted, TEAM constitutes the most complete and well-developed framework available to evaluate the economics of proposed transmission upgrades. It provides a consistent methodology to identify benefits, incorporates a process to reflect the impact of bids on market prices, and integrates decisions regarding generation and transmission investment. Standardization between the Commission and CAISO with respect to these broad requirements of future transmission evaluation studies will significantly assist regulatory decision-making and therefore enhance the efficiency of the regulatory review process for economic transmission upgrades in a restructured electricity environment.

In order to describe the fundamental elements of TEAM, this document organized as follows:

II. Applicability of TEAM

The CAISO recognizes and strongly supports the concept that the economic analysis regarding potential transmission projects represents only one of the many criteria that stakeholders must consider when investing in the future transmission infrastructure of California. Other important considerations that may not be fully considered in the current TEAM approach include:

- Project siting, schedule and cost risk
- Public acceptance
- Difficult-to-quantify environmental impacts (e.g. water, aesthetic)
- Difficult-to-quantify contingencies or extreme events (e.g. new market paradigms, terrorist acts)
- Support of state resource policy goals (e.g. renewables, distributed generation)
- Enhancing operational flexibility
- Secondary reliability benefits

The economic analysis, however, remains a critical part of any transmission evaluation and is the focus on the CAISO's TEAM application. As noted, the CAISO demonstrated the methodology proposed in TEAM for two separate studies – Path 26 and PVD2. Each of these studies demonstrated the TEAM methodology and required significant CAISO resource commitment in order to implement and complete. Stakeholders in these studies occasionally expressed the following questions regarding the application of TEAM:

- Is a particular application included in the CAISO's r Path 26 and PVD2 studies a minimum (or mandatory) study requirement for an CAISO-acceptable evaluation of a potential transmission project?

- Are there other types of transmission feasibility studies that may not require the same depth of analysis for a reasonable conclusion?

The CAISO suggests that it is practical to develop standards for an acceptable economic evaluation depending on the category of study. For that purpose, CAISO suggests that the TEAM principles are necessary in some form for the following types of studies:

- ***Reliability Projects*** **–** Reliability projects are considered primarily for the reliability benefits they provide, and are evaluated on a "least-cost" basis. The least-cost portion not only includes all associated project and operating costs, but also includes the economic benefits that may be associated with a selected upgrade. For example, two alternatives may satisfy the same reliability need and have identical costs, but if one allows for lower system losses, or a different generation commitment, these impacts need to be economically evaluated and included the in the "net least cost" calculation.

- ***Economic Projects (Inter-Regional)*** **–** Economic projects are considered primarily for the economic benefits (e.g., reduction in system operating costs) that they provide, and are evaluated on a "net present value" basis. These economic projects can be further subdivided into large, inter-regional projects, and smaller intra-regional projects. The two studies that the CAISO performed (Path 26 and PVD2) would be considered as large, inter-regional projects evaluated primarily on the basis of their economic benefits. The level of analysis required for this type of project is generally more substantial than the other two categories of studies.

- ***Economic Projects (Intra-Regional)*** **–** Projects that impact primarily a single region or utility may require a less rigorous economic analysis. These projects might include utility-level upgrades and intra-regional projects, such as the proposed San Francisco trans-bay cable alternative.

III. Description of Requirements Continuum

Since the study requirements for the Inter-Regional Economic Projects are the most rigorous, those specifications will be outlined first. The other two categories will then be compared to the inter-Regional Economic Project requirements.

These requirements will be described by key principle. The following terms will be used in describing the analytical tasks or data / software capabilities for a study:

- ***Requirement*** – CAISO considers this as a minimum threshold for an acceptable study. If there are exceptions to this requirement, they will be clarified with a footnote.
- ***Recommended*** – CAISO strongly recommends that that this element be included, but stops short of making it required at this time.
- ***Preferred*** – CAISO strongly encourages this feature be part of the study, but recognizes that there may need to be additional research in this area for this feature to be practically implemented
- ***Optional*** – CAISO does not currently have a strong preference for this study element either primarily due to the difficulty in implementing it or a perceived lack of value.
- ***Unacceptable*** – CAISO will not accept studies with this attribute

IV. Description of TEAM Key Principles

The TEAM methodology is built around five key principles that are summarized below:

	Key Principle	Description
1	Benefit Framework	Methodology for calculating project benefits.
2	Network Representation	Use of physical transmission model capable of forecasting nodal prices.
3	Market Prices	Inclusion of potential bid strategies to forecast market prices.
4	Uncertainty	Methodology for understanding impact of uncertainty on results.
5	Resource Alternatives	Identification and consideration of alternative resource strategies and projects.

The basic study requirements for a proposed economic, inter-regional transmission project are summarized below:

CAISO Study Requirements
For Proposed Economic, Inter-Regional Transmission Project

	Key Principle	Study Attribute	Notes
1	Benefit Framework	- Demonstrate revenue identify	CTL - GR = TR
		- Demonstrate benefit identify	Total benefits = ΔPC = ΔCS + ΔGS + ΔTS
		- Compute participant benefits *	WECC subregions, CAISO market participants, non-CAISO participants, sum equal to societal
2	Network Representation	- DC-OPF model with nodal pricing	AC power flow optional; transportation model is unacceptable for prospective studies, but are permitted for current studies so long as the results are/were confirmed with a nodal model.
		- Current SSG-WI database	Minimum of one cost-based reference case with SSG-WI data for comparability purposes
3	Market Prices	- Inclusion of credible bid strategies *	Bid strategies must be theoretically sound and reflect system dynamics and pivotal ownership; prefer benchmark with regional prices
4	Uncertainty	- Develop expected value and distribution of benefits *	Recommend benefit histograms and consideration of capital cost risk
5	Resource Alternatives	- Identify, consider, and discuss resource alternative(s)	Alternatives include specific resource types and portfolios
	Other Requirements	- Operating, capacity, system loss, environmental, insurance, and other benefits *	Benefits in addition to energy need to be identified and quantitatively considered as appropriate and feasible
		- Multiple years	Minimum of two study years, 5 or more years apart. Additional successive years are discouraged.
		- Chronology	Minimum of 168 chronological hours per week, 12 weeks per year, preference is 8760 hours per year.

* Study attribute not required if cost-based reference case has lifecycle, societal BCR greater than 1.5.

These study requirements are discussed in greater detail below.

A. Benefit Framework – The benefit framework recognizes that there are several important equations that should hold true for any study (we refer to these as revenue and benefit "identities" since they are always valid). The benefit framework also helps stakeholders to determine the societal, as well as the relevant participant benefits. The study attributes for the benefit framework are listed below:

1. **Revenue identity (requirement) –** On a societal level, the following equation must always be valid for any simulation, for any hour (or larger time period):

   CTL – GR = TR

   where CTL = cost of load
   GR = generator revenue
   TR = transmission revenue

   The difference between what the consumers pay for energy, and what the generators receive for energy, is equal to the transmission revenue.[2]

2. **Benefit identity (requirement) --** On a societal level, the following equation must always be valid when comparing two simulations (one case) for any hour (or larger time period):

   Total benefits = ΔPC = ΔCS + ΔGS + ΔTS

   where Δ PC = difference in total system production costs
   Δ CS = difference in total consumer surplus
   Δ GS = difference in total generator surplus
   Δ TS = difference in total transmission surplus

   The total societal benefits are equal to the difference in production costs (plus capital and fixed costs if there is a different resource mix between the simulations). The total benefits are also equal to the change in consumer, generator, and transmission (owner or operator) surplus.[3]

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[2] The CTL is the Cost-Of-Load to the consumer and is equal to the consumer energy requirement multiplied by the energy price (for each hour, and for each node or zone). The GR is equal to the generator production multiplied by the energy price (for each hour, and for each node or zone). And the TR depends on the market scheme – it can either be equal to wheeling revenues in a contract-path market, or congestion revenue in a Locational Marginal Price (LMP) market.

[3] The Consumer Surplus is defined as the difference between the value of power, and the cost of power for that consumer. Since the value of power is difficult to define, and this term cancels out if the load is inelastic between simulations, the Consumer Surplus can also be defined as the difference in CTL for the two simulations. If the CTL goes down with the transmission addition, there is a Consumer Surplus. The Generator Surplus is defined as the generator net profit (energy revenue minus variable cost of production). And the Transmission Surplus is the difference in transmission revenue between the two cases.

3. **Participant benefits (requirement)** – At a minimum, determine the relative benefits and costs to the following subgroups:[4]
   i. WECC subregions (e.g. CA, SW, NW, RM)
      1. consumers
      2. generators
      3. transmission owners
   ii. CAISO market participants
      1. consumers
      2. utility generators
      3. non-utility generators
      4. utility transmission owners
      5. non-utility transmission owners
   iii. Non-CAISO market participants
      1. municipal utilities **(optional)**

4. **Participant benefits – modified perspective (recommended)** – The participant benefits described above are based on forecast cash flows. The CAISO has developed an additional perspective that excludes "monopoly profit" (i.e. generator profits from uncompetitive market conditions). The reason for excluding these profits is that one of the CAISO's primary goals is to ensure a healthy, competitive California energy market. According to this perspective, generator profits resulting from market power should not be included in a measurement of the benefits to the California market.[5] Since calculation of the modified participant benefits requires enhancements that are not currently implemented in most software packages, this study attribute is not required at this time.

B. **Network Representation** – The energy benefits and costs of a proposed transmission upgrade need to be modeled accurately. The study attributes for the network representation are:

   1. **DC OPF Transmission Model (requirement)** – Either an AC power flow or a DC OPF transmission model must be used in any prospective study. At this point, the AC power flow is optional, and the DC OPF is the minimum standard. The network model must be capable of deriving nodal prices so that the correct economic impact of a proposed transmission upgrade can be correctly computed. A transportation model is

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4 For more information regarding the calculation of participant benefits, please refer to TEAM Report, Chapter 2 "Quantifying Benefits", and Appendix B "Demonstration of Transmission Benefit Calculation Using a 3-Node Prototype Model."

5 See TEAM Report, Chapter 2, starting on p. 2-10, for additional information on "modified perspective."

not unacceptable for future studies since it computes contract transmission flows instead of physical flows. However, for current studies, i.e., PVD2, a transportation model is acceptable with verification of results through the use of a nodal model.

2. **SSG-WI database (requirement)** – For purposes of validation and comparison, at least one cost-based reference case ("without" and "with" simulations, for multiple years) must be completed with the most recent SSG-WI database. If the project proponent feels that the SSG-WI database would strongly benefit with additional data revision, updating, or inclusion of proprietary data, the majority of cases may be performed with this "enhanced" database. However, a single case will need to be developed using the original SSG-WI data for the reasons explained above.

C. **Market Prices** – Economic evaluations have frequently been performed assuming a perfectly competitive market in which generators make power available at their marginal cost. Clearly, this is only part of the wholesale market picture. Hence, the impact of market power and bid strategies must be considered. The study attributes for market prices are:

1. **Inclusion of bid strategies (requirement)** – Unless the cost-based reference case provides a societal BCR over 1.5 (i.e. the proposed project is very economic), coherent and credible bid strategies should be developed, justified, and implemented.

2. **Dynamic bid strategies (recommendation)** -- Bid strategies should be able to change frequently enough so that the system dynamics are reflected on an hourly basis. The bid strategies will change for potential price setters based on system conditions (e.g., load, available generation and transmission, fuel prices, etc.) and opportunities for pivotal players. A "dynamic" bid strategy that can change with these conditions is preferred over a "static" bid strategy that is the same for every hour of the day irrespective of system conditions and market opportunities.

3. **Benchmark with regional prices (preferred)** – Detailed benchmark studies can be resource-intensive and of questionable benefit if they are not developed correctly. However, some indication of how well the proposed bid strategies perform in predicting either current or historical regional prices is valuable. Therefore, a high-level benchmark study is preferred.[6]

D. **Uncertainty** – The expected value of benefits can vary significantly from the reference or base case. Therefore, appropriate sensitivity cases need to be developed and summarized for the expected value as well as the distribution of benefits.

1. **Inclusion of sensitivity cases (requirement)** – Sensitivity studies designed to understand the expected value and distribution of benefits of a proposed transmission project are considered critical by the CAISO if the societal BCR is less than 1.5. Sensitivity studies need to include some extreme cases and single-parameter-modification cases.[7]

2. **Development of histograms (recommendation)** – A histogram shows the probability of various benefit ranges, with the total probability for all ranges equal to one. These histograms provide a visual summary of the relative benefit uncertainty and can be used to qualitatively or quantitatively compare alternatives.

3. **Development of potential range of capital costs (preferred)** – Although the CAISO proposed methodology did not focus on assessing the risk on the capital cost side of the equation, this information is important, and if available, should be included in some form in the analyses.

4. **Use of importance sampling (preferred)** – Currently, it is not feasible to develop sufficient cases (using a physical network model in a traditional Monte Carlo type of approach) to derive statistically-defensible results. Therefore, some type of methodology to reduce the number of potential cases to a manageable level is advisable. Importance sampling, as explained in the CAISO reports, can be used as a concept for achieving this reduction in a reasonable and defensible manner.

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[6] A high-level benchmark study may incorporate historical loads, hydro, and gas prices at a regional level, but would not try to true up generator and transmission availability on a unit level. The benchmark might be more of a directional comparison than an absolute price comparison.

[7] See TEAM Report, Chapter 5 "Sensitivity Case Selection".

After the number of cases is reduced, some type of credible mechanism to assign probabilities to the remaining cases is necessary.[8]

E. **Resource Alternatives** – One of the primary economic values of a proposed transmission project is that the project may displace the need for alternative resources. Also, the proposed project may facilitate a different resource mix or portfolio than is achievable without the transmission upgrade. It is important to identify and consider these resource alternatives.

1. **Identify, consider, and discuss resource specific or portfolio alternatives (requirement)** – A proposed transmission upgrade may displace specific resources (e.g., in-basin combined cycle) or facilitate a different resource mix (e.g. increased renewables). These considerations can be important from not an economic, but also a policy, perspective.

F. **Other** – There are several other study attributes that are important for transmission evaluations. These attributes are as follows:

1. **Multiple years (requirement)** – Since the study is intended to represent the benefits for a 30 to 50-year economic life, at least two years must be evaluated. These two years should be at least 5 years apart. Multiple years in succession are generally less valuable than isolated years or additional sensitivity cases.

2. **Chronology (requirement)** – For each year evaluated, at least 12 weeks per year, 168 hours per week, need to be simulated -- 8760 hours per year is recommended.

3. **Unit Commitment (recommended)** – Software and associated data should be able to perform unit commitment and consider chronological parameters such as ramp rates, minimum up- and down-times.

4. **Hydro Optimization (preferred)** – It is desirable that the software and associated data be able to provide some level of hydro optimization, so that static hourly hydro patterns are not used irrespective of changes in input parameters.

V. Summary of Standards

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[8] In the PVD2 Report, the CAISO used the Importance Sampling Concept and a Maximum Log-Likelihood linear program to assign probabilities. See, PVD2 Report Technical Appendices, Appendix A "Scenario Selection".

The study standards explained in the preceding section are for a single type of study – a large, economic, Inter-Regional Transmission Project (that does not demonstrate a strongly positive BCR for a cost-based reference case). However, these study requirements can vary for different study types. The requirements as applied to different studies are summarized as follows:

CAISO Study Requirements for Alternative Study Types

	Key Principle	Reliability	Economic -- Inter-Regional	Economic -- Intra-Regional
1	Benefit Framework	possible	Yes	yes
2	Network Representation	possible	Yes	yes
3	Market Prices	possible	Possible	no
4	Uncertainty	possible	Possible	possible
5	Resource Alternatives	No	Yes	yes
	Other Requirements	possible	Possible	possible

A. Reliability – Reliability projects are evaluated on the basis of least-cost, net of any economic benefits that differ between alternatives. If the CAISO or other party evaluates a reliability project, the impact of the difference in potential economic benefits should be estimated. If this difference between alternatives is significant compared to the difference in capital costs, then the economic benefits should be computed. In other words, if the economic benefits may change the least-cost ranking of alternatives, these economic benefits should be considered. Otherwise, economic benefits can be ignored.

As explained above, the designation of "sometimes" in the above-table for reliability projects indicates that the CAISO study requirements are necessary only if the economic benefits may change the least-cost ranking. In the case where the economic benefits may be a significant factor, and if it appears that the inclusion of market prices and uncertainty are not likely to substantially improve the economic differential estimate or conclusion, then these study requirements can also be waived. However, a discussion regarding why these factors were excluded from the analysis is necessary.

Resource alternatives are not required in the economic analysis since it is assumed that the resource alternatives have been identified from a reliability perspective and are being evaluated in the reliability study.

B. **Economic Projects (Inter-Regional)** -- These study requirements are outlined in Section IV – CAISO Study Requirements. If the benefit-cost-ratio (BCR) for the proposed transmission upgrade is significantly positive (BCR greater than 1.5), then it is not necessary to derive market prices or uncertainty since the recommendation to proceed is unlikely to change with the additional information.

C. **Economic Projects (Intra-Regional)** – Intra-regional projects can be considerably less complex with respect to the economic analysis than the Inter-regional proposals. In that vein, the study requirements are generally more relaxed. If the economic impact can be considered to be primarily limited to a single region, the region can be modeled with external markets from a societal basis to understand the benefits and compare these benefits to other alternatives. If there are clear economic differences at this level between alternatives, it may not be valuable to perform a more detailed study requiring market prices and sensitivity cases. In any case, the benefit framework needs to be utilized, a network model must be used, and resource alternatives to the proposed transmission line need to be considered.

(END OF ATTACHMENT 1)

CALIFORNIA ISO

California Independent
System Operator

Proposed Principles for the Economic Evaluation of Transmission Projects

CPUC Workshop
September 15, 2005

Eric Toolson
Consultant, California ISO

Summary of Key Principles

	Key Principle	Brief Description
1	Benefit Framework	Methodology for calculating societal and participant benefits.
2	Network Representation	Use of physical transmission model capable of forecasting nodal prices.
3	Market Prices	Inclusion of potential bid strategies to forecast market prices.
4	Uncertainty	Methodology for understanding impact of uncertainty on results.
5	Resource Alternatives	Identification and consideration of alternative resource strategies and projects.

Benefit Framework

- Revenue identity
  CTL – GR = TR
- Benefit identity
  Total benefits = ΔPC = ΔCB + ΔGB + ΔTB
- Compute participant benefits (as appropriate)
  Market segments (consumer, generator, transmission owner)
  WECC Subregions
  CAISO Ratepayers and Participants
  Non-CAISO Participants

Benefit Framework Example

- PVD2 Study, 2008, BHBM (load, gas price, hydro, market price)
- WECC Societal benefits = ΔPC = ΔCS + ΔGS + ΔTS
  - PC without = $27,525 mil.
  - PC with = $27,435 mil.
  - PC dif. = $90 mil.

  - Consumer benefit = $197 mil.
  - Producer benefit = $178 mil.
  - Transmission owner benefit = ($285) mil.
  - Total Benefit = $90 mil.

Network Representation

- DC OPF (or AC power flow) required so that accurate, physical transmission flows can be modeled
- Current SSG-WI (or successor) database used for at least one cost-based reference case.
  - Understand whether potential differences in results are due to data or modeling reasons

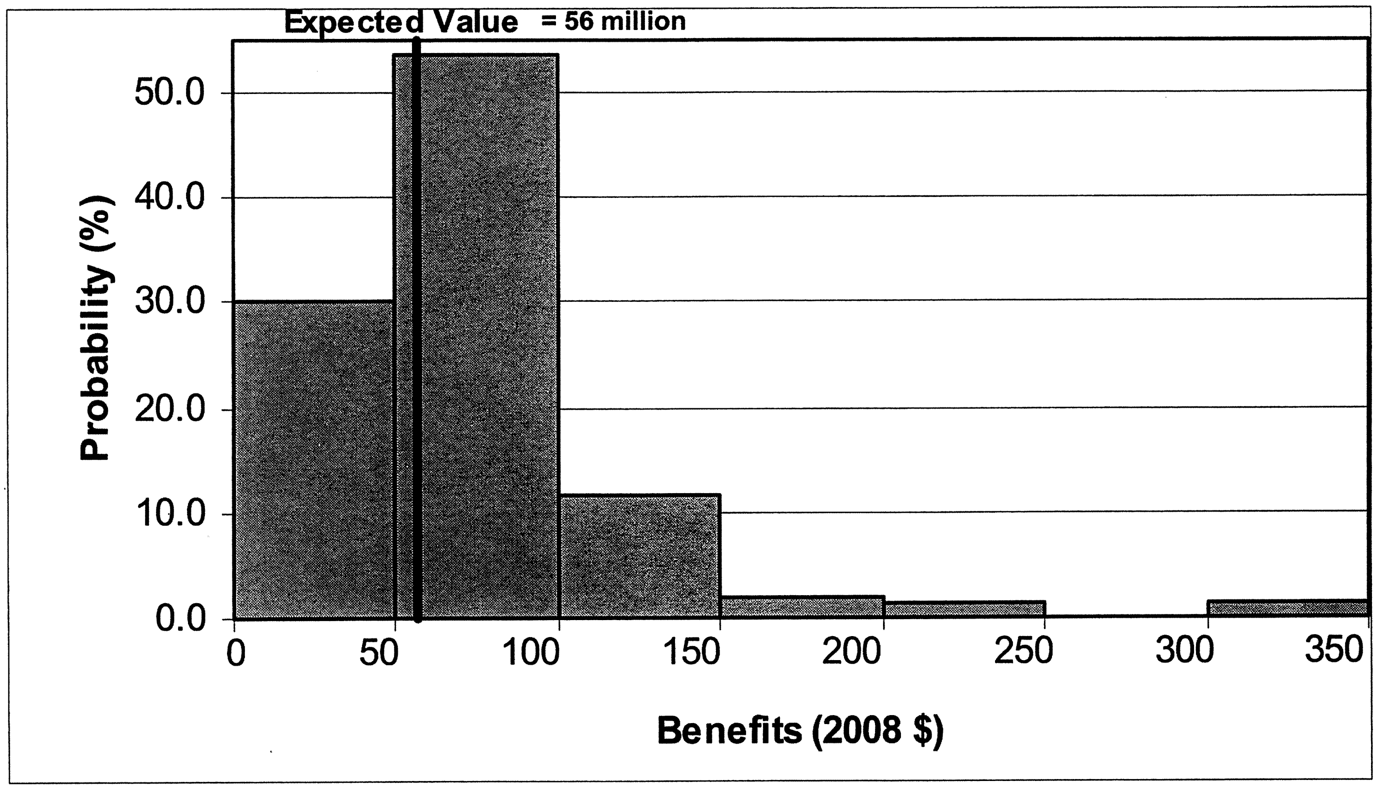
Market Prices

- Develop and implement credible bid strategies
  - Should be dynamic (can change hourly) and not static (same bid strategy for many hours)
  - Should reflect system conditions (supply/demand situation)
  - Should reflect market opportunities (pivotal players)

Uncertainty

- Develop expected value and distribution of benefits
  - Reference case and expected value can be significantly different, particularly for participant perspectives
  - Distribution of benefits important to understand value of extreme events and risk of adverse outcomes, and indication of insurance value

Probability Distribution for 17 Cases of System and Market Conditions 2013 Energy Benefits* (mil. 2008 $)



*CAISO Ratepayer Perspective; 2013 has been deflated to 2008 for purposes of comparison.

Resource Alternatives

- Identify and consider potential resource alternatives
  - Specific resources (CC versus increased transfer capability from out-of-state)
  - Resource portfolios (increased access to renewables)

Other Proposed Requirements

- **Additional benefits** -- Consider other benefits not captured in market simulation – may include capacity, system loss, environmental, insurance, etc.
- **Multiple years** – Minimum of 2 study years, 5 or more years apart
- **Chronology** – Minimum of 168 chronological hours per week, 12 weeks per year

Types of Economic Analyses

	Key Principle	Reliability	Economic -- Inter-Regional	Economic -- Intra-Regional
1	Benefit Framework	possible	yes	yes
2	Network Representation	possible	yes	yes
3	Market Prices	possible	possible	no
4	Uncertainty	possible	possible	possible
5	Resource Alternatives	no	yes	yes
	Other Requirements	possible	possible	possible

Definitions

- Consumer Benefit represents the reduction in cost to consumers.
- Producer Benefit is the increase in producer net revenue.
- Transmission Owner Benefit is the increase in congestion revenues.
- WECC Societal is sum of Consumer, Producer, and Transmission Owner Benefit in WECC.

  Also equal to difference in total production costs for the "without" and "with upgrade cases.
- WECC Modified Societal is same as Societal but excludes Producer Benefit derived from uncompetitive market conditions.
- ISO Ratepayer includes ISO consumers and utility-owned generation and transmission revenue streams.
- ISO Participant includes ISO Ratepayer plus the CA IPP Producer Benefit derived from competitive market conditions.

(END OF ATTACHMENT 2)

ATTACHMENT 3

CALIFORNIA ISO

California Independent
System Operator

Five TEAM Principles (Transmission Economic Assessment Methodology)

CPUC Workshop on PVD2
September 14, 2005

Anjali Sheffrin, Ph.D.
Department of Market and Product Development

Purpose of Economic Evaluation

- Determine category of benefits that can be quantified
- Compare expected project benefits to the costs to determine impact on entire WECC, Sub-region, and California ratepayers
- Determine if investment is cost-effective for ratepayers
- Understand range, uncertainty, and potential up-side of benefits of line

Goals of TEAM Effort

- Develop a common methodology to evaluate economic need for transmission upgrades.
- Present a framework which can be used to make consistent and effective decisions on transmission upgrade.
- Provide transparency in methods, databases and models so a variety of stakeholders can understand the implications of a transmission upgrade.

Five Key Principles of TEAM

1. **Benefits Framework** - Standard framework to measure benefits regionally and separately for consumers, producers, and transmission owners in different regions.
2. **Network Representation** – Demonstrate flow is physically feasible in a network model.
3. **Market Prices** – Utilize market prices rather than costs to evaluate transmission expansion.
4. **Uncertainty** - Consider impact of wide range of future system conditions -- dry hydro, gas prices, demand growth, under- and over-entry of generation. Illustrative of insurance value.
5. **Generation/Demand-Side Substitution** – Review alternatives to transmission expansion.

Application of TEAM to PVD2 Study

I. **Benefits Framework --** Utilized standardized benefit cost frame to calculate WECC wide benefits and regional impacts.

II. **Network representation** – PLEXOS, full network represented with 17,450 lines, with 3 DC lines and 284 lines 500KV or above enforced.

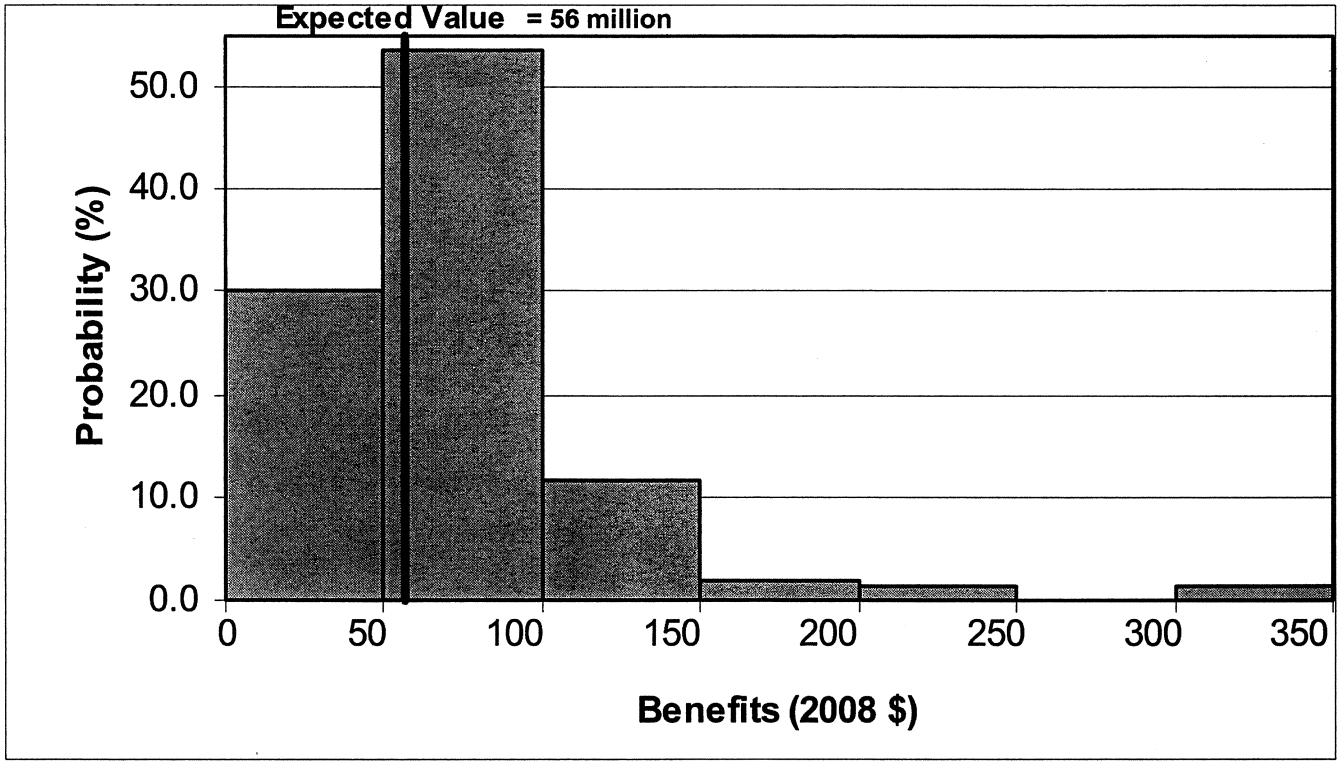
III. **Market prices-** Dynamic hourly bidding based on empirically estimated price cost mark-up which vary by system conditions.

IV. **Uncertainty-** 30+ sensitivity cases for 2008 based on various assumptions on load growth, gas prices, hydro conditions, and market pricing. Provides expected value, distribution of benefits, and indication of insurance value.

V. **Resource substitution-** Alternative transmission and generation projects were studied

70% probability that benefits will exceed $50/yr

Probability Distribution for 17 cases of System and Market Conditions
2013 Energy Benefits*
(mil. 2008 $)



*Energy Benefits for range of system conditions. CAISO Ratepayer Perspective (Enhanced Comprtition); 2013 has been deflated to 2008 for purposes of comparison.

All four perspectives show a positive benefit to cost ratio
Summary of Results
(Lifecycle amounts, millions of 2008 $)

	WECC or Societal	Enhanced WECC Competition or Modified Societal	CAISO Ratepayer (Enhanced Competition)
Levelized Benefits			
- Energy	$56	$84	$57
- Operational	$20	$20	$20
- Capacity	$12	$12	$6
- System Loss	$2	$2	$1
- Emissions	$1	$1	$1
- Total	$91	$119	$84
Levelized Costs	$71	$71	$71
Benefit-Cost Ratio	**1.3**	**1.7**	**1.2**

Public Process

- In Feb. 2003, CAISO filed general blueprint of economic methodology and held a public workshop March 14, 2003 to fully review methods.
- In Dec. 2003, CPUC ALJ requested full implementation of methodology to be demonstrated using network model.
- In 2004 CAISO held 3 Public Workshops, 12 technical calls
- Comprehensive review and recommendation provided by Market Surveillance Committee (MSC), CEC (CERTS review)
- Filed Full TEAM report with CPUC on June 2, 2004.

PVD2 Public Process

- **Southwest Transmission Expansion Plan**
  - 18 public meetings over the last 2 1/2 years
  - STEP support of the PVD2 Project at February 9, 2005 meeting
- **1/11/05 – Western Arizona Transmission Studies (WATS) group**
- **1/14/05 – ISO Stakeholder Meeting**
- **1/18/05 – ISO Market Surveillance Com. Meeting**
- **3 Board presentations; Work papers published on Web**
- **2/22/05 - ISO MSC Opinion Issued**
- **2/24/05 - Unanimous ISO Board approval of PVD2**

(END OF ATTACHMENT 3)

Assessment of An Economic Analysis of the Palo Verde-Devers Line Number 2 (PVD2) Transmission Network Upgrade

by
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Market Surveillance Committee of the California ISO

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1. Introduction

We have been asked by the ISO management and Board of Governors to assess the results of the report "Economic Evaluation of the Palo Verde-Devers Line No. 2 (PVD2)," prepared by the ISO's Departments of Market Analysis and Grid Planning. The report describes the results of an application of the ISO's Transmission Economic Assessment Methodology (TEAM) to the PVD2 upgrade. We have previously commented on the TEAM approach.[1] We discussed aspects of its application to the PVD2 project at several MSC meetings and have met several times with ISO staff to review simulation results. We have also received written comments on the PDV2 analysis from Southern California Gas, Los Angeles Department of Water and Power, and Southern California Edison. On February 4, 2005, we held a public conference call where we received additional comments on this report[2] from stakeholders. We are grateful for this very helpful input.

We have also been asked to provide an opinion on whether the ISO Board should approve this transmission upgrade. Our overall conclusion from reviewing ISO's report on the PVD2 upgrade and stakeholder comments on this report is that the Departments of Market Analysis and Grid Planning have, for the most part, undertaken a conservative economic analysis of the expected benefits of this proposed upgrade. Their modeling results imply a wide range of plausible scenarios for future system conditions that yield significant net benefits to California ISO ratepayers from the upgrade. Appendix D of the Technical Appendices notes that substantial amount of new generation is currently planned or under construction in Arizona. The PVD2 line will provide California consumers with access to a significant share of the energy that will be produced by these very efficient natural gas-fired generation units that are less expensive to build and operate in Arizona as opposed to near Southern California load centers.

The remainder of this opinion summarizes why we believe that this application of the TEAM methodology provides credible, yet conservative, estimates of the expected benefits of the PVD2 upgrade to California ISO ratepayers and why we recommend that the ISO Board approve this transmission expansion. Based on the ISO analysis, the PVD2 upgrade represents a sound investment offering a sound rate of return and an insurance policy against future adverse, potentially catastrophic, market conditions. Because TEAM is an evolving methodology and subject to continual improvement, we also suggest enhancements that we believe are worth considering for future applications.

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[1] CAISO Market Surveillance Committee, "Comments on the California ISO's Transmission Expansion Assessment Methodology (TEAM)" June 1, 2004, http://www.caiso.com/docs/2004/06/01/200406011457422435.pdf.
[2] ISO Draft PVD2 Report posted on the ISO website on Feb 2, 2005.

2. Sources of Energy Cost Savings from Upgrade

A transmission expansion typically allows cheaper distant energy to substitute for higher-priced locally produced energy. How large this benefit is depends on a number of factors that are unknown at the time the upgrade is considered. The TEAM methodology solves this problem by using its best estimate of the configuration of the transmission network and stock of generation capacity available in the Western Electricity Coordinating Council (WECC) at the time the proposed transmission expansion would be operational and computes the ex-post benefits of the expansion for a number of possible realizations of future system conditions. These system conditions differ in terms of the expected growth in electricity demand, the level of input fuel prices, hydrological conditions in the Pacific Northwest and remainder of the WECC, the amount of new investment in generation capacity, the availability of key transmission and generation facilities, and the extent of unilateral market power that suppliers are able to exercise. The ISO has forecasts for these future system conditions from a number of sources.

Load Growth: 10-year load forecasts published by the WECC are used for all regions besides California. The load forecasts used for California were computed by the California Energy Commission (CEC). These figures are used to construct three possible future load scenarios--baseline, low and high. The low and high load scenarios are designed to provide a 90 percent confidence interval on the level of future load throughout the WECC. Although future demand levels above the high load scenario and future demand level below the low load scenario are possible and are likely to lead to a wider range of benefit estimates for the upgrade, the ISO's procedure provides credible range of future demand conditions in the WECC.

Input Fuel Prices: Natural gas prices are a major source of uncertainty in assessing the benefits of this upgrade because so many existing generation units in California burn natural gas at heat rates significantly above that of a state-of-the-art combined cycle natural gas turbine (CCGT) facility, the typical unit currently being constructed in Arizona. Although oil prices tend to fluctuate with natural gas prices, very little energy is produced from oil-fired units in the WECC. Although coal produces a significant amount of the electricity produced in the WECC, its price is unlikely to change significantly, and coal is rarely on the margin. Three scenarios for gas prices are selected based on the CEC natural gas price forecasts and the estimated forecast errors. The baseline price scenarios are for 2008 and 2013 are broadly consistent with recent futures prices for Henry Hub natural gas for 2008 to 2010 from the New York Mercantile Exchange. The average of the high scenario natural gas prices is approximately double the level of average prices for the baseline scenario, although these high scenario prices are well below the levels of natural gas prices reported in California during the period December 2000 to May 2001 and are approximately equal to the historical highs for Henry Hub natural gas prices. The average price for the low price scenario is roughly half the average for the baseline scenario. These prices seem overly optimistic in terms of a future low price scenario. Anticipating too low of a price scenario would tend to underestimate the benefits of the transmission upgrade because the benefits of substituting high heat rate units in California for low heat rates units in Arizona is much less with lower natural gas prices. The reasonableness of the baseline and high price scenario and the overly optimistic low price scenario all imply that the methodology yields conservative estimates of the future benefits of the transmission upgrade.

Hydrological Conditions and Future Generation Resources: A major driver of the benefits of transmission upgrades is the mix of available generation resources in California and the rest of the WECC. In particular, the amount of hydroelectric energy available in British Columbia, the

Pacific Northwest and California is a major driver of the benefits of the transmission expansion. The methodology assumes that California meets its renewable portfolio standards. In addition, California is also assumed to have enough new thermal generation capacity to meet a 15 percent planning reserve margin. Known generation retirements in California were built into these planning reserve scenarios. The reserve margin assumption limits the magnitude of potential benefits from the upgrade because it eliminates insurance value that the upgrade provides against years in the future when there is less than a 16 percent planning reserve. The methodology accounts for uncertainty in future hydrological conditions by specifying energy availability under baseline, wet and dry hydro conditions using data compiled by the Seams Steering Group--Western Interconnection (SSG-WI) Planning group. The total amount of hydroelectric energy assumed available in the Pacific Northwest under the low hydro scenario is significantly above the levels observed in 2000 and 2001. Because lower hydro conditions yield higher benefits from the upgrade, this implies that the ex-post benefits associated with low hydro scenarios are likely to be a lower bound on the ex-post benefits of the upgrade under actual low hydro conditions, which can be considerably more severe than those assumed in the methodology. Again, these modeling assumptions imply conservative estimates of the benefits of the upgrade.

Impact of Market Pricing: Transmission upgrades typically increase the number of independent suppliers able to compete to sell energy at a specific location in the transmission network. For the PVD2 upgrade, suppliers located near the Southern California load centers will face greater competition from suppliers located in Arizona. The ISO's methodology accounts for the greater competition suppliers face as a result of the upgrade by using historical data on California price-cost margins to model the impact of this increased competition on the level of price-cost margins reflected in market prices. The level of mark-ups anticipated by the methodology are relatively low, as a result of the comparatively high levels of forward contracting assumed in the ISO's analysis. Nevertheless, the results show that CAISO participants and consumers benefit significantly from the modeled decreases in those mark-ups. We note that it is possible that the assumption of no mark-ups outside of California might result in some error in the estimates of the value of the PVD2 upgrade, but it is not clear a priori if this would bias the benefit estimates upward or downward. As we have stated in our previous opinions on transmission evaluation, estimating mark-ups is an uncertain and ambiguous task, and basing mark-up projections on past behavior and allowing alternative scenarios as has been done in the TEAM methodology is an appropriate approach. We encourage the ISO to continue to explore alternative approaches to modeling the impact of transmission upgrades on market prices. We look forward to working with ISO staff on modeling this very important component of the value of transmission upgrades in a wholesale market regime.

3. Other Sources of Benefits from Transmission Upgrades

The ISO's methodology incorporates other sources of benefits from a transmission upgrade besides those due to energy cost savings. These include system operation benefits, transmission loss savings, capacity cost benefits, emissions savings benefits, and additional benefits from alternative congestion management paradigms outside of California. Although these benefit sources clearly exist, they are significantly more difficult to quantify in a rigorous manner. Therefore, in the PVD analysis, they were quantified outside of the PLEXOS runs used to quantify energy cost savings. Potentially, improvements in PLEXOS or other market simulation models would allow these other benefits to be quantified simultaneously and consistently with energy savings. We encourage the ISO to consider the development or use of such improved methods and stand willing to assist the ISO staff in this effort.

System Operation Benefits: The ISO operators estimate that as a result of the PVD2 line there will be less need to keep generation units local to the Southern California load centers operating in real-time in order to manage the constraints implied by N-1 and relevant N-2 operating criteria that are not captured in the TEAM. Appendix K of the ISO's Technical Appendices discusses the current costs of managing congestion and re-dispatch costs because of these operating criterion. The annual cost of managing this constraint is just above $93 million and will decrease to just below $50 million with the short-term upgrades coming in June of 2006. The ISO operations staff estimates that it is likely that the PVD2 upgrade will further reduce these costs by 25 to 50 percent. This estimated operational cost savings yields $18 million benefits per year in 2004 dollars.

While we concur that these are the best estimates available at the present time of operational cost savings as a result of the PVD2 upgrade, we would have preferred a more detailed analysis incorporating unit commitment costs into the PLEXOS model to arrive at these cost saving estimates. However, this would assume efficient day-ahead management of congestion, rather than the real-time management given day-ahead schedules that takes place in a multi-settlement locational marginal pricing (LMP) market.

Transmission Loss Savings: The ISO's energy price benefits analysis does not account for transmission line losses in setting locational marginal prices. To the extent that the upgrade reduces the level of line losses, this is a tangible source of economic benefits. Appendix J of the ISO Technical Appendices presents a methodology for measuring benefits from line loss reductions and finds tangible, but not excessive benefits from reducing line losses. Ideally, the market simulation software would calculate losses endogenously. Although the capability to do this at the level of detail represented in PLEXOS is not now available, it is technically feasible to develop such a capability, and it should be considered in future analyses.

Capacity Savings Benefits: Appendix M of the ISO Technical Appendices provides a comparison of the estimated costs of constructing and operating a combined cycle natural gas turbine (CCGT) generation unit in California versus Arizona. Both construction costs and operating maintenance costs are assumed to be lower for units built in Arizona versus those built in California. These capacity savings are estimated to amount to roughly $12 million on an annual basis. The large amount of new generation planned and under construction in Arizona--roughly 5,000 MW of new capacity by 2008 and an additional 5,000 MW of capacity between 2008 and 2013 according to Appendix D of the ISO Technical Appendices--implies clear cost savings as a result of constructing generation capacity in Arizona versus California. However, further details on the sources of these cost differences would provide greater credibility to the capacity cost savings figures in the report. We note that these construction and operating costs have been studied extensively in the eastern ISOs as they have designed their resource adequacy mechanisms, and that despite this effort the estimates remain both controversial and uncertain.

Emissions Savings Benefits: The ISO report notes that generating more electricity from new units in Arizona will reduce the amount of natural gas consumed in the WECC because higher heat rate units located near the Southern California load centers will be displaced by the new lower heat rate units located in Arizona. Valuing the benefits of these emissions reductions is complicated by the fact that there is no transparent price for NO_X emissions permits in Southern California or Arizona. Fortunately, the ISO's estimate of the emission savings benefits is extremely modest, approximately $1 million annually, which should not impact the decision to construct the transmission line. If those benefits were considerably larger, we would recommend that the explicit modeling of emissions caps in the market modeling software be considered.

Alternative Congestion Management Schemes Outside of California: A complaint of a number of stakeholders with the ISO's methodology for determining the energy savings associated with a transmission upgrade is the fact that an locational marginal pricing (LMP) market is assumed to exist outside of California, as well as within California. There are two issues here. One is whether the dispatch and costs resulting from the LMP assumption are a reasonable approximation of operations under the actual transmission pricing systems in place in the West. The ISO's extensive calibration and validation of the PLEXOS simulations gives us confidence that the answer to that question is yes. The second issue is whether the distribution of transmission rents resulting from LMP adequately represents the actual split among market participants, given the mix of transmission pricing mechanisms. It is clear that there is at least one circumstance where there is a significant divergence that affects the welfare of California market participants.

The ISO report addresses this second issue in Appendix N by specifying a mechanism for refunding congestion charges to various market participants located outside California and in California in a manner that attempts to replicate the existing mechanism used to manage congestion into Southern California and allocate its costs to consumers in and outside of California. The alternative congestion management mechanism implies even greater benefits associated with the transmission upgrade. Table VII.4 of the ISO report shows that the expected benefits of the upgrade to Californians under this alternative mechanism for congestion management are almost triple the expected benefits assuming that LMP is used throughout the WECC. This results from transferring selected transmission rents from ISO participants to non-ISO participants, so that decreases in those rents no longer appear as a cost to ISO participants.

Although we cannot verify the exact numbers, we do indeed expect that this alternative mechanism would result in a significant increase in benefits to CAISO participants. This is because the rents on lines into Southern California that the LMP method assumes are earned by CAISO participants instead partially accrue to Southwestern market participants. Thus, when the PVD2 line is installed and the transmission rents in that area decrease, this is not actually experienced as a loss by CAISO participants, although under LMP there would be such a loss.

4. Alternatives to PVD2

Though the projected benefits of the PVD2 upgrade appear to justify the estimated upgrade 2009 online cost of $680 million, it is reasonable to ask whether these benefits could be realized with a lower cost alternative to the PVD2 upgrade. To answer this question, the ISO considered two viable alternatives--building additional generation inside California and alternative transmission projects.

The benefits of PVD2 are estimated under the assumption that there is generation expansion in Southern California (see Table D.2, Technical Appendix D). The key issue is whether even more generation inside California could replace the transmission upgrade. The ISO report argues that additional generation inside California is infeasible and is unlikely to accrue the same benefits as the transmission upgrade, because it is cheaper to build generation in Arizona than California. This seems like a reasonable conclusion based on existing evidence. However, just as importantly, a transmission upgrade provides greater flexibility than new generation, because the PVD2 upgrade leaves a wider range of generation--both inside and outside of California--competing to provide energy to load inside California. This healthy mix of suppliers provides an important backstop against extreme market conditions, such as those observed in the 2000-2001.

As a result of stakeholder input, the CAISO analysis of PVD2 considers several transmission alternatives to the PVD2 upgrade. Most importantly, the analysis considers whether the PVD2 upgrade could be replaced by the proposed East-of-River project ("EOR 9000"), which would increase the EOR path rating from 8,055 MW to 9,300 MW, an increment of 1,245 MW. At the January 18, 2005, MSC meeting, the CAISO staff presented the results of sensitivity analyses where the benefits of the PVD2 line were estimated with and without the EOR 9000 upgrade. The analysis suggests these projects are complements and should both be pursued.

5. Conclusion

There is a wide range of realized benefits of the project, primarily because of the uncertainty in future market conditions in the Western Electricity Coordinating Council (WECC). There are a range of future system conditions--demand growth, natural gas prices, hydroelectric energy availability, and the extent of unilateral market power exercised by suppliers--where the project would have limited realized benefits, in part because of the conservative modeling assumptions made by the ISO. However, there are also ranges of future system conditions, where the project would have realized benefits substantially in excess of the cost of the project. The ISO estimates that the probability is greater than 70 percent that future system conditions will occur such that the project realizes benefits in any given year that exceed the annualized cost of the project. The strength of the TEAM approach is that it is able to estimate this probability or the entire distribution of realized values of the project over all possible future system conditions in an internally consistent manner. Although it would be desirable to have run additional scenarios, we believe that the method used to define scenarios and assign probabilities to them is reasonable.

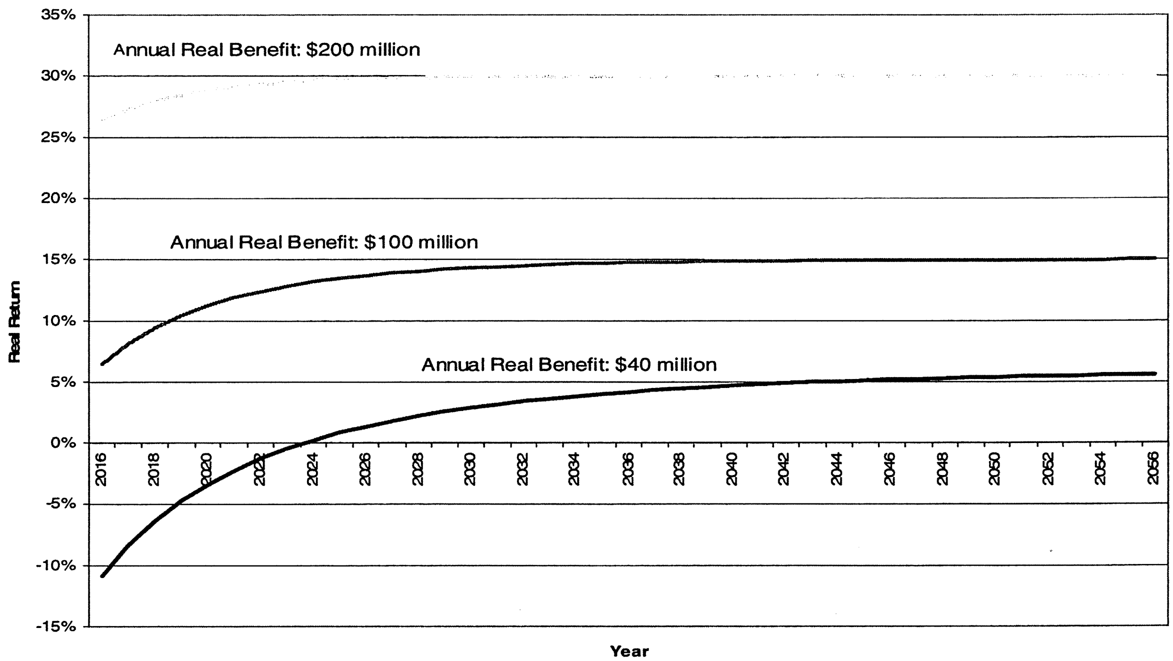
As we emphasized in our earlier discussion of the TEAM approach, transmission projects need to be viewed not just in terms of their expected benefits but in terms of the insurance they provide against adverse, and potentially catastrophic, outcomes. Extreme market conditions (e.g., high energy prices or blackouts) disrupt business and society in a way that exacts a toll beyond the high-energy prices incurred during these periods. This standard is consistent with other aspects of the State energy action plan, such as a focus on the diversification of fuel sources through extensive support of renewable energy. Thus even if the expected benefits were negative, a project can have significant value under some future scenarios. A negative expected value of a project could be viewed as the insurance premium against these catastrophic outcomes. The significant probability of realized values in excess of the annualized cost of the project suggests that this project is an insurance policy that is very likely to yield substantial ex post benefits.

Though the PDV2 upgrade provides an important insurance policy, it does so while also providing a sound rate of return and a relatively quick payback for the expected price tag of $667 million (in 2008 dollars). The ISO provides benefit savings for only two years – 2008 and 2013. A simple way to view these benefit estimates is to consider two questions (1) in how many years would the transmission project recoup its cost and (2) if the annual benefits accrue over a long horizon, what is the return on the $667 million investment. Even at the very low range of estimated annual benefits from *only* energy savings ($40 million, table VII.1), the PVD2 upgrade breaks even in 2024 and offers a real rate of return over 5% (see figure 1). At more realistic annual levels of

$100 or $200 million, the PVD2 upgrade breaks even in 2014 and 2011 (respectively) and offers an attractive long-run real rate of return of between 15 and 30 percent.

The evaluation of transmission expansion is an extremely complex task. The Departments of Market Analysis and Grid Planning have done provided a comprehensive analysis of the benefits of this upgrade using state-of-the-art methods. As noted above, a number of factors argue in favor the ISO's estimate of the expected benefits of the PVD2 upgrade being conservative. The substantially higher expected benefits of the upgrade under a congestion management mechanism for the rest of the WECC that is more representative of the current scheme argues in favor these benefit estimates being conservative. Finally, the more than 10,000 MW of new generation that are reported to be planned for Arizona by 2013 provides further evidence that there would be substantial benefits to the PVD2 line. For these reasons, we recommend that the ISO Board move forward with this transmission upgrade.

Figure 1: Real Rate of Return on PVD2 Upgrade (assuming annual real benefits of $40, $100, or $200 million and a project cost of $667 million).



Note: Assumes initial real project cost of $667 million is incurred year-end 2007, while benefits begin accruing year-end 2008.

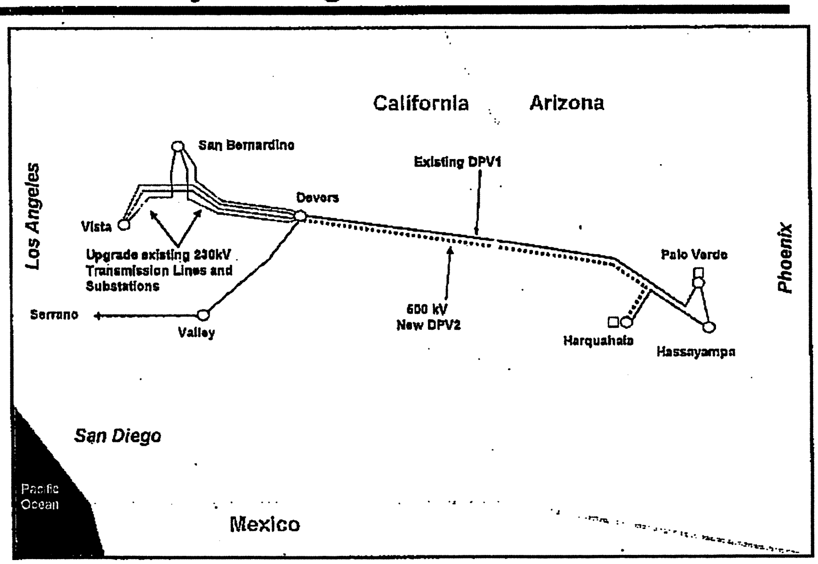
(END OF ATTACHMENT 4)

Cost Effectiveness of Constructing Devers-Palo Verde No. 2

CPUC Workshop

September 14 and 15, 2005

DPV2 Project Diagram



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Presentation Contents

- TEAM Principles
  - SCE's application of the five TEAM principles
- Transmission Access Charge
  - Background, and description of impact on a customer's bill
- Comparison of CAISO/SCE Analyses (CAISO/SCE)
  - Showing of analogous methods
- SCE's Economic Analysis
  - Background; Potential Benefits; SCE's Methodology and Analysis; Results; Description of Benefits; Costs; Discount Rate; AFUDC; Project Alternatives; Base Case Inputs
- Misc. Questions and SCE Answers

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THE FIVE TEAM PRINCIPLES

Application of Five Key TEAM Principles* to Determine DPV2's Benefit-to-cost ratio

	TEAM	SCE
Benefits Framework	• Standard framework to measure benefits regionally and sub-regionally for consumers, producers, and transmission owners.	• Same three primary metrics identified in the CAISO's Benefits Framework; namely consumer surplus, producer revenues, and transmission owner revenues. SCE also included the secondary benefit consisting of 3rd party transmission revenues.
Market Prices	• Utilize market prices to evaluate transmission expansion.	• Market prices were used to evaluate the benefits of transmission expansion.
Uncertainty	• Consider through wide range of scenarios for future system conditions-(dry hydro, gas prices, demand growth, under and over entry of generation).	• Monte Carlo (i.e., stochastic) simulations for various factors which include variations in hydro conditions, gas prices, and demand growth.
Network Model	• Demonstrate power flow is physically feasible, corresponding to economic analysis	• Economic analysis incorporated Southern California Import Transmission limits and SCE also performed separate power flow analysis to demonstrate the physical feasibility of the project
Generation / DSM Alternatives	• May evaluate alternatives to transmission expansion.	• SCE demonstrates how additional renewable and conventional generation, and demand side management do not meet the project objectives

* As described in the CAISO's June 2004 TEAM report available at the CAISO website (http://www2.caiso.com/docs/2003/03/18/2003031815303519270.html)

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THE CAISO TRANSMISSION ACCESS CHARGE

Background of CAISO's Transmission Access Charge (TAC)

- Transmission rate increases are reflected in the CAISO's TAC
  - The TAC is a FERC-jurisdictional rate administered by the CAISO
  - DPV2 will increase TAC rates as new High Voltage transmission facilities being added to the operational control of the CAISO
- The TAC recovers costs of transmission facilities under the CAISO operational control
  - TAC is a volumetric charge applied to all entities using transmission service. Three components to TAC rates are:
    - Existing High Voltage transmission facilities – transitioning to grid-wide rate
    - New High Voltage transmission facilities (≥ 200 kV) – already grid-wide rate
    - All Low Voltage transmission facilities(< 200 kV) – each PTO pays own costs
- TAC rates are adjusted whenever the Transmission Revenue Requirements (TRR) of any PTO changes
  - SCE changes its TRR only with FERC approval via a FERC rate case
  - New High Voltage transmission TRR changes TAC rates based upon a load ratio share of PTOs to total load in the CAISO area

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WHO PAYS FOR THE COSTS OF NEW HIGH VOLTAGE TRANSMISSION?

1) **TAC customers:** Retail Customers of PTOs in proportion to their load ratio share of CAISO load:

SCE (~ 43%)	Banning (~ 0.1%)
PG&E (~ 43%)	Pasadena (~ 0.6%)
SDG&E (~ 10%)	Riverside (~ 0.9%)
Anaheim (~ 1%)	Vernon (~ 0.6%)
Azusa (~ 0.1%)	

2) **Direct access customers:** For PTOs that have direct access customers who pay transmission rates would also pay for a portion of DPV2.

3) **Wheeling Access Charge customers:** Customers of Non-PTOs that take Wheeling service over the ISO controlled grid. These customers pay the ISO's Wheeling Access Charge ("WAC"). The WAC rate is equal to the TAC rate. Minimal amount of service compared to TAC.

4) **Existing Transmission Contract Customers:** Customers of Non-PTOs that have Existing Transmission Contracts ("ETCs") with SCE, and whose ETC rate is tied to the costs of SCE's TRR. Also a minimal amount of service compared to the TAC.

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The process leading up to adding DPV2's costs to SCE's customer's bill

- SCE constructs DPV2 and tabulates final costs (revenue requirements)
- SCE files a new transmission rate case requesting recovery of DPV2 costs
- After FERC approval, these costs are added to the CAISO's TAC
- Costs of DPV2 are added to the transmission component of SCE's customers' electric service bills
- A portion of DPV2's costs are recovered from other CAISO system users and returned to SCE transmission customers
  - TAC: shared among participating transmission owners
  - WAC: via increased Wheeling revenues rebated by ISO to SCE
  - ETCs: via increased ETC transmission rates paid to SCE

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Comparison of the CAISO's and SCE's Economic Analyses of DPV2

- Comparison of methods
- Comparison of analyses
- Comparison of data inputs

SCE and CAISO Utilized Analogous Methods to Determine the Project's Benefit-to-Cost Ratio

Metric	• Both use a benefit-to-cost ratio
Benefits	• Both use the same math to calculate primary benefits: ▪ consumer surplus, producer revenues, and transmission owner revenues
Multiple Perspectives	• Both evaluate CAISO area ratepayer and WECC wide benefits; ▪ CAISO also evaluates other perspectives
Evaluation of Uncertainty	• Both agree it's essential to evaluate uncertainty ▪ SCE – stochastic based ▪ CAISO – probabilistic scenario based
Costs	• Both utilize SCE's estimated project costs

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Comparison Between SCE's and the CAISO's Analysis

Data to Determine CAISO Ratepayer Impact	CAISO	SCE
Input data, such as loads	CAISO's input data started with a PacifiCorp database modified by the CAISO and stakeholders	SCE's input data comes from internal forecasts (load), external forecasts (natural gas prices), and Global Energy Decisions (formerly Henwood) forecasts
Meets Renewable Portfolio Standards	Yes, in CA and WECC wide	Yes, in CA, not WECC wide
Losses	Post-processed	Modeled
Wheeling Costs	Not included	Modeled
Environmental Costs (marketable emissions)	Post-processed	Modeled
Generator Pricing	Market Based and cost-based	Cost-based
Transmission Representation	500 kV line ratings enforced, lower rated lines not enforced; DC representation	All WECC line ratings enforced
Generator Operation	Average heat rates with no other commitment parameters; operating benefits were post-processed	Incremental heat rates and generation operating parameters (start-up; ramp rates; min-up/down, commit parameters)

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Comparison Between SCE's and the CAISO's Input Data

Data to Determine CAISO Ratepayer Impact	CAISO	SCE
Loads – peak and energy (	2008 MW GWh CAISO 51,271 261,641 Southwest 28,110 140,807	2010 MW GWh CAISO 48,400 246,700 Southwest 28,400 138,900
WECC Resources Peak (MW)	2008 - 196,000	2010 - 190,000
WECC Peak (MW)	2008 - 150,296	2010 - 145,500
WECC 2010 Planning Reserve Margin	30%	30%
Gas Prices ($/mmBtu) Diff. CA / SW	$4.70 2008 $/mmBtu in 2008 $0.37	Real 2004 $/mmBtu $4.40 in 2012 $0.37
Emission Costs	NOx - $40,000 / ton SOx – Not Modeled	NOx - $2,600/ton SCAQMD SOx - $300 to $600 per ton WECC wide
Discount Rates	10 %	10.5%
Inflation Rates	2.0 %	Global Insight Spring 2004 GDP inflator (1.3% to 2.3%)

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SCE's Economic Analyses of DPV2

- Background
- Potential and quantified benefits
- SCE's analysis, inputs, calculations, results, alternatives
- Estimated benefits
- Estimated costs and cost descriptions

Background

- SCE's cost-effectiveness evaluation of DPV2 uses the same principles and methods as the CAISO's proposed T.E.A.M.* methodology
- SCE quantified major costs and benefits
  - Benefits with lesser impacts were not quantified
- Focus is on impact to those paying for the project; ratepayers in the CAISO control area
- SCE expects the project to provide about $1.1 billion in lifecycle benefits with a benefit-to-cost ratio of 1.7:1

* Transmission Economic Assessment Methodology

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Potential Benefits of DPV2

- Increased market competition
- New generation development
- Insurance value against extreme low-probability, high impact contingencies
- Increased operational flexibility
- Interconnection support between control areas
- Provides access to over 6,500 MW of new generation available in the Southwest

What SCE's analysis is based upon

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SCE's Economic Analysis Method

Project Screening	Project Order	Setting a Baseline	Project Evaluation
• Define Project objective • Identify Projects meeting objective (STEP) • Estimate total production cost benefits with deterministic production simulation • Utilize rough understanding of costs (w/o field studies) • Use NPV of revenue requirement as screening metric	• Use NPV to filter out non-viable projects • Examine timing of remaining projects • Determine viability of timing (any project sponsors?) • Order viable projects per their operating dates	• Add planned new generation • Add planned new transmission • Add highly cost effective projects from screening • Baseline complete	• Full stochastic analysis • Incorporate fuel, load, and hydro volatilities • Complete technical studies to define project scope • Complete cost studies • Update input assumptions prior to CPCN filing • Refresh stochastic analysis to update cost effectiveness

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Project Order and Setting the Baseline

Screening

Add screened alternatives
- EOR series capacitors
- DPV2

Trans New Entry

Principles used to add transmission
- New lines are added that affect the market model topology
- Construction should be fairly certain
- Ratings and WECC system impacts should be fairly certain
- Utility specific projects – such as DPV2

Generation New Entry

Principles used to add generation
- Project is being constructed and has a reasonable likelihood of being completed (either substantially, and have financing completed, or be an investor owned or municipality utility project). SCE also added generation if public data reasonably

Generation Retire-ments

Principles used in generation retirements
- Specific published retirement dates,
- Reach a life of 55 years or,
- Retirements due to air quality restrictions
- Consistency with California Commission planning assumptions

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Base Case Inputs

	Demand	Supply	Transmission	Base Case
Includes	• Hourly representation • Forecasts based on FERC 714 filings, and WECC or utility specific forecasts • Henwood internal analysis sanitizes forecasts • DSM explicitly accounted for in CA forecasts • Distributed generation • Direct Access • Municipalities • T&D losses • Direct load control	• Generator unit level information • Natural gas and other fuel forecasts • Simulates planned and unplanned outages • New Gen. entry • Retirements after 55 years • New renewables as a result of RPS requirements	• Aggregate transmission lines between zones to form transmission paths • Transfer capability • New entry if new line effects model, construction and rating are fairly certain.	• Least cost dispatch at the zone level • Demand and Supply balances at every zone • Outputs specific generating station data, path utilization, energy not served, and Market Clearing Prices (MCP) • Henwood periodically back-tests for internal validation
Excludes	• Customer initiated demand response	• Ownership rights • Bilateral contracts	• Potential outages • Contracts • Ownership rights • Specific line losses (captured in load forecasts) • Automatic nomogram limitations	• Power flows or stability results.

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Overview of Calculations to Derive Benefits to Ratepayers in CAISO Area

- Estimate lifecycle benefits by calculating the change in Total Production Costs to ratepayers in the CAISO area using T.E.A.M.
  - Short-term benefits using multi-year run of production simulations (2009-2014)
    - Stochastic expected value, typical hour, and typical week
  - Calculate change in consumer costs, URG producer revenues, and transmission owner revenues for ratepayers in CAISO area
- Also calculate lifecycle third party transmission revenue benefits
- Extrapolate to estimate long-term benefits
  - 2015-2055 held at zero real inflation starting from 2014 benefits
- Present value all benefits to 2005 to use as numerator in the project's benefit-to-cost ratio

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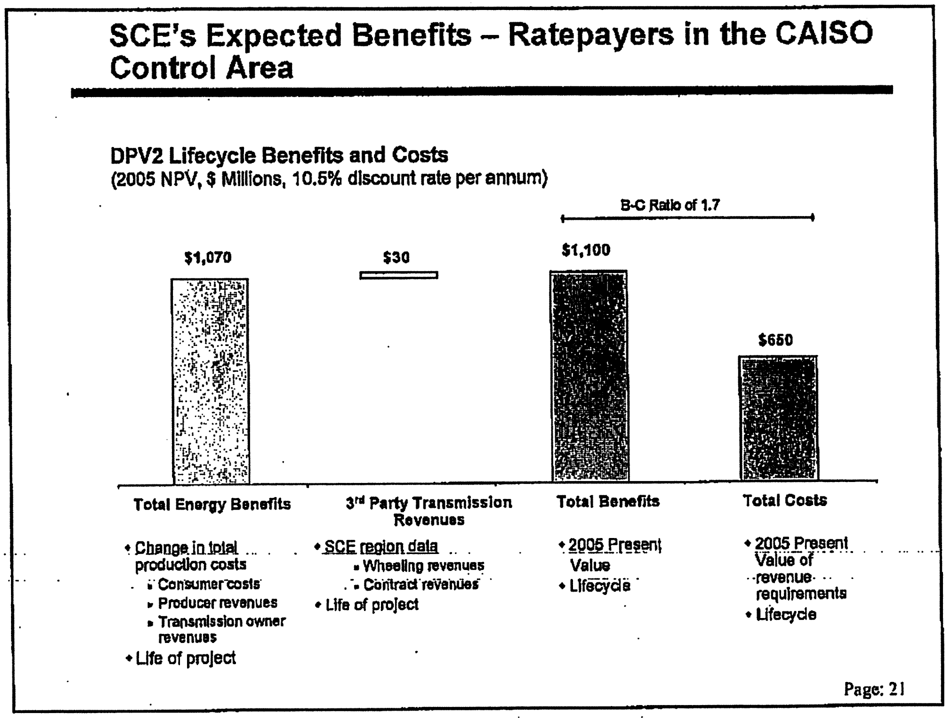
SCE's Expected Benefits – Ratepayers in the CAISO Control Area
DPV2 Lifecycle Benefits and Costs
(2005 NPV, $ Millions, 10.5% discount rate per annum)
B-C Ratio of 1.7
$1,070
$30
$1,100
$650
Total Energy Benefits
3rd Party Transmission Revenues
Total Benefits
Total Costs
• Change in total production costs
▪ Consumer costs
▪ Producer revenues
▪ Transmission owner revenues
• Life of project
• SCE region data
▪ Wheeling revenues
▪ Contract revenues
• Life of project
• 2005 Present Value
• Lifecycle
• 2005 Present Value of revenue requirements
• Lifecycle
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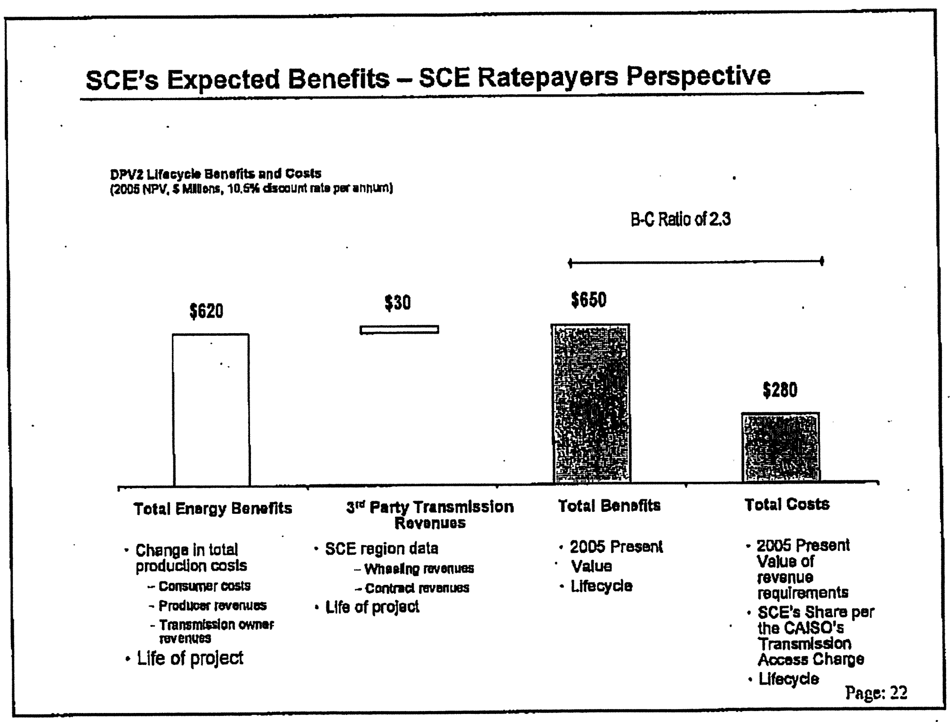
SCE's Expected Benefits – SCE Ratepayers Perspective
DPV2 Lifecycle Benefits and Costs
(2005 NPV, $ Millions, 10.5% discount rate per annum)
B-C Ratio of 2.3
$620
$30
$650
$280
Total Energy Benefits
3rd Party Transmission Revenues
Total Benefits
Total Costs
• Change in total production costs
– Consumer costs
– Producer revenues
– Transmission owner revenues
• Life of project
• SCE region data
– Wheeling revenues
– Contract revenues
• Life of project
• 2005 Present Value
• Lifecycle
• 2005 Present Value of revenue requirements
• SCE's Share per the CAISO's Transmission Access Charge
• Lifecycle
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Description of Benefits

Energy Benefits

- Estimated as the change in total production costs
- Total benefit is estimated to be about $ 1.1 billion for the life of the project.

Third Party Transmission Revenue Benefits

- Payments by non-CAISO ratepayers that lower CAISO transmission revenue requirements are a benefit to DPV2. Incremental ISO Wheeling service and Existing Transmission Contracts' (ETCs) payments will reduce DPV2's overall transmission revenue requirement.
- Increases to Wheeling Revenue are based on historical Edison Wheeling revenue information. Increases to ETC revenue is based on the ratio of the Transmission Revenue Requirements with and without DPV2 multiplied by the ETCs' revenues (Colton, and LADWP contracts).
- Total benefit is estimated to be about $ 30 million for the life of the project.

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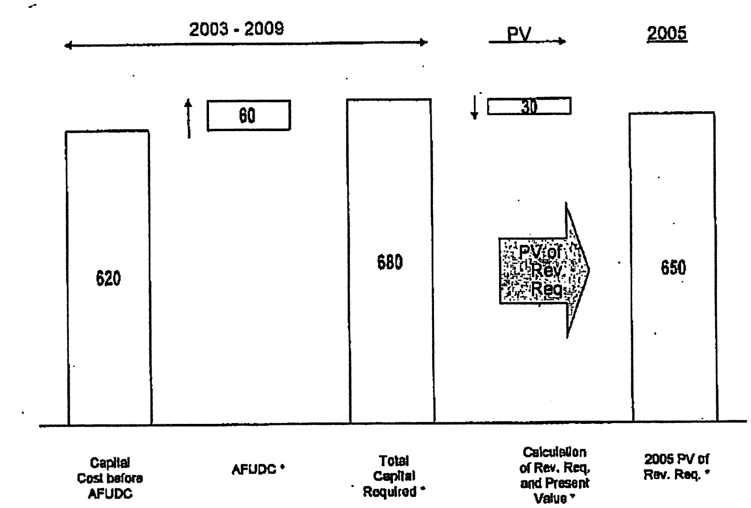
DPV2 Cost Components ($ Millions)



* Treasurer's Revenue Requirements Model

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The Discount Rate used in DPV2's Analysis is Equal to SCE's Incremental Cost of Capital

- SCE estimates its incremental weighted cost of new capital to be 10.50%

Capital Component	Capital Ratio	Cost	Incremental Weighted Cost of Capital
o Debt	47.0%	8.15%	3.83%
o Preferred	5.0%	7.15%	0.36%
o Common	48.0%	13.15%	6.31%
TOTAL	100.0%		10.50%

- SCE uses this cost of capital to discount future streams of benefits and costs
  - Nominal revenue requirements discounted into year end 2005 dollars

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AFUDC (Allowance for Funds Used During Construction)

- During DPV2 construction, the return on invested capital used to finance the project is capitalized and recovered over the life of the asset
  - Capitalized amount known as Allowance for Funds Used During Construction (AFUDC)
  - AFUDC has a Debt and Equity (Equity plus Preferred) portion
- Forecasted AFUDC assumes capital expenditures at beginning of year, resulting in a full year of accrued AFUDC
  - Assume incremental weighted costs of capital (10.5%) as AFUDC rate

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AFUDC Example

Calculation of Construction Work in Process (CWIP)

	Year 1	Year 2	Year 3
Beginning CWIP	0.0	110.5	232.6
Add:			
Capital Expenditures	90.0	90.0	0.0
Capitalized Property Taxes	10.0	10.0	0.0
AFUDC	10.5	22.1	24.4
Less:			
Project Closure to Rate Base	0.0	0.0	257.0
Ending CWIP	110.5	232.6	0.0

Calculation of Allowance for Funds Used During Construction (AFUDC)

	Year 1	Year 2	Year 3
Beginning CWIP	0.0	110.5	232.6
Capital Expenditures	90.0	90.0	0.0
Capitalized Property Taxes	10.0	10.0	0.0
Capital Costs Financed by Investors	100.0	210.5	232.6
Projected Authorized Cost of Capital	*10.5%*	*10.5%*	*10.5%*
Return on Invested Capital (AFUDC)	10.5	22.1	24.4

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Alternatives Considered

- Economic Wire alternatives
  1. Second Southwest Power Link 500 kV transmission line (SWPL)
  2. Second Devers–Palo Verde 500 kV transmission line (DPV2)
  3. Upgrade SWPL No. 1, Devers–Palo Verde No. 1, Navajo–Crystal, and Moenkopi–Eldorado series capacitors (Path 49 Series Capacitor Upgrades)
  4. New Imperial Valley–Devers 500 kV transmission line (IV–Devers)
  5. Combination of constructing a new Imperial Valley–Devers 500 kV transmission line and upgrading SWPL No. 1, Devers–Palo Verde No. 1, Navajo–Crystal, and Moenkopi–Eldorado series capacitors (IV–Devers & Path 49 Series Capacitor Upgrades)
- Technical Wire alternatives
  - Convert DPV1 to a DC line
  - Increase compensation on DPV1
  - East of River 9000+ project is a complementary project and is not expected to impact DPV2's benefits
- Non-wire alternatives do not meet project objectives
  - Demand-side alternatives, generation, renewables, and distributed generation alternatives do not meet project objectives of accessing energy in the southwest, providing incentive for new generation development, increasing generation competition, and supporting SCE's resource plan goals. Without DPV2, ratepayers would also have to forego the estimated 1.1 billion dollar benefits of the project (See, SCE's Proponents Environmental Assessment, Volume 1, Part 2, Purpose and Need section 2.2.4.3)

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Misc. Questions

- Should production simulations use thermal transmission line rating limits or operational limits?
  - Economic projects should be analyzed using operational transmission line limits to reflect grid restraints
- How would participation of LADWP affect economic analysis?
  - LADWP pays a percentage of DPV2's costs without decreasing DPV2's benefits, therefore the project's benefit-to-cost ratio improves.
    - SCE's base case assumes that LADWP does not participate and that LADWP retains 368 MW of transmission service on DPV1
    - However, if LADWP does participate, the benefits remain the same since LADWP's share of DPV1 becomes available
- How were emissions treated (carbon adder CPUC rule)
  - CO_2 emissions were tracked and DPV2 results in overall reduction in CO_2. CPUC rules require the use of carbon adders for the ranking of generation bids for contracts with terms greater than 5 years. The CPUC has no requirements to use carbon adders for project evaluation.

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(END OF ATTACHMENT 5)

ATTACHMENT 6
Principles for Transmission Economic Assessment Methodologies

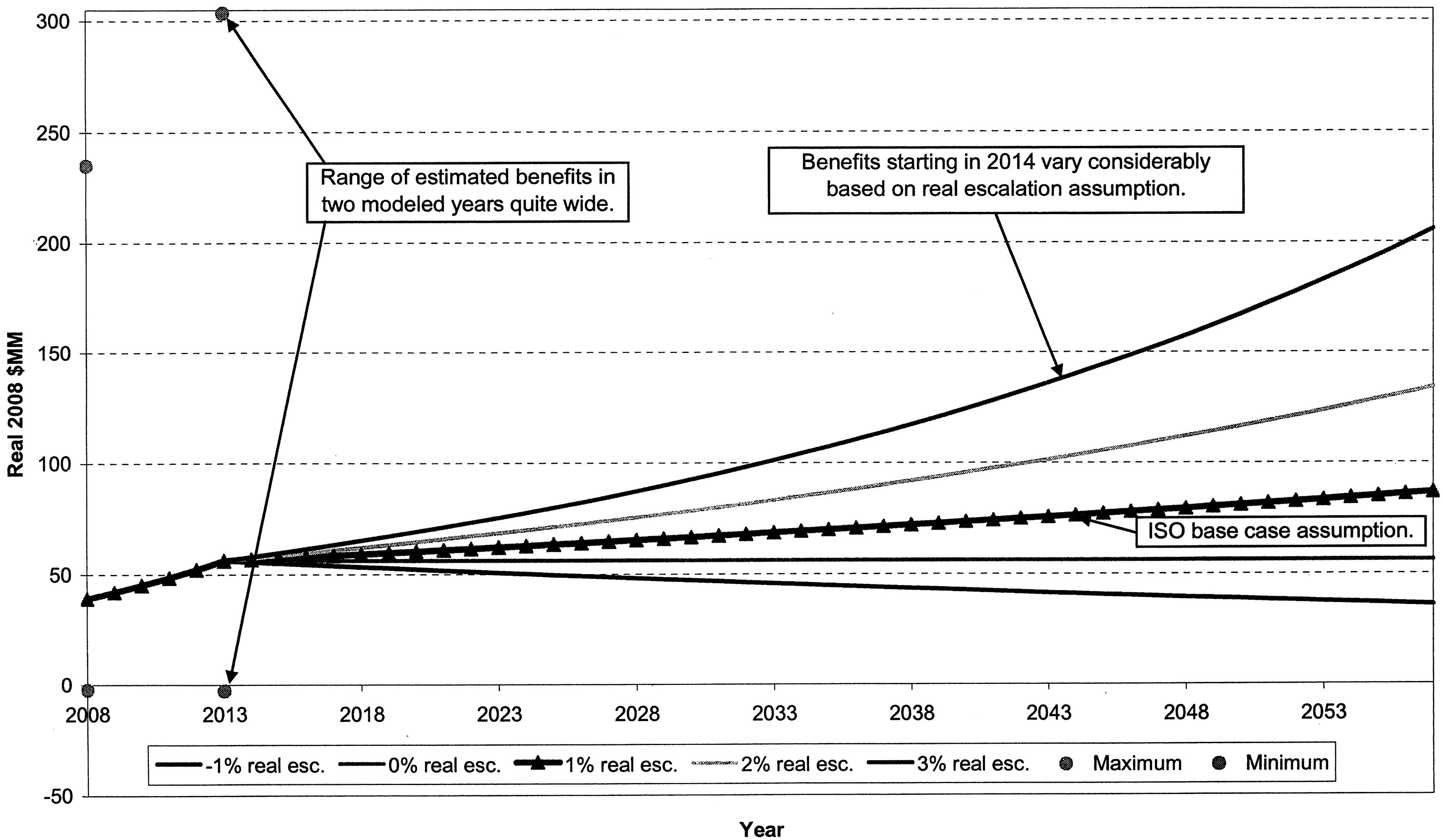
Step	Description	Application to DPV2
1. Specify Decision to be Made	Decisions may be based on greater or lesser amounts of analysis, depending on the magnitude and finality of decision	CPUC facing final decision on whether SCE should proceed with $600 MM project CPUC thus needs substantial review of projects' potential benefits and costs
2. Establish Appropriate Decision Criteria	Economic decisions should be based on clear criteria established in advance Criteria may include non-quantitative or non-quantifiable factors as well	Benefit-Cost Ratio to CAISO Ratepayers should comfortably exceed 1.00 (e.g., 1.2) over life of project, as discounted at IOU cost of capital Payback period should be approximately 10 years or less ISO TEAM decision criteria not clear
3. Develop Measures of Benefits and Costs	Appropriate definitions and measures of benefits and costs should be defined	Focus on DPV2 is "energy benefits", that is, access to lower cost energy from the Southwest ISO TEAM made substantial contributions to methods for measuring such benefits
4. Gather and Analyze Data	Analysts gather and analyze data needed to quantify benefits and costs specific in Step 3	Substantial review of projects' benefits and costs needed, *particularly the identifiable key drivers of projects' expected benefits*
5. Reach Conclusion	Based on above steps, reach conclusion regarding authorizing project based on criteria established in Step 2	Both SCE and CAISO believe project is cost-effective
6. Maintain Flexibility	Decision methods must be adaptable to different circumstances	Future studies will undoubtedly differ from those performed for DPV2

(END OF ATTACHMENT 6)

Prepared for Office of Ratepayer Advocates
By Woodruff Expert Services
For September 14 & 15 Workshop in A.05-04-015 & I.05-06-041

ATTACHMENT 7

Uncertainty of Annual Gross Energy Benefits of DPV2 projected by CAISO



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Data developed from *Board Report, Economic Evaluation of the Palo Verde-Devers Line No. 2,* California ISO, Department of Market Analysis & Grid Planning, February 24, 2005

(END OF ATTACHMENT 7)